INTERMOUNTAIN POWER SERVICE CORPORATION

August 24, 2001

Mr. Richard Sprott, Director
Division of Air Quality
Department of Environmental Quality
P.O. Box 144820
Salt Lake City, UT 84114-4820

Attention: Milka Radulovic

Dear Director Sprott:

IPSC NOTICE OF INTENT: BACT Resubmittal and Corrections

On April 4, 2001, Intermountain Power Service Corporation (IPSC) submitted a Notice of Intent (NOI) to modify the Intermountain Generating Station (IGS) in Delta, Utah. IPSC has been submitting other information as requested for the NOI, including corrections, additional details, and a Best Available Control Technology (BACT) analysis. As a result of our discussions with Division of Air Quality staff, we feel it is necessary to provide further clarifications to both our NOI and the BACT analysis. In fact, the attached BACT is a retransmittal with substantive changes that more clearly outline and support our recommendations.

NOTICE of INTENT DISCUSSIONS

BACT

IPSC is proposing to make modifications to Unit One and Two at IGS that will ultimately increase capacity. The modification that will directly impact emissions is increased fuel use. Other modifications are being made to increase the efficiency in energy conversion and power delivery. Because of the impact of increased fuel throughput, IPSC is also proposing to make modifications to keep this up-rate project minor for criteria pollutants.

Specifically, in order to prevent an increase in NOx, we are proposing to either modify how we combust coal, or install new technology low-NOx burners. Currently, IPSC is leaning toward combustion modification as the most cost effective method of NOx controls. Since IGS already has low-NOx burners installed, a permit change modifying the current NOx emission limit should be

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sufficient for BACT for this type of project. The DAQ has the authority, and as described in it's own guidance policy, the ability to agree with this determination. IPSC is providing herewith a revised BACT analysis with stronger supporting arguments.

Minor Modification vs. Major Modification

IPSC has previously addressed potential emission impacts that can result from the proposed up-rate project. In particular, we have determined that with the proposed increase in fuel use combined with modifying combustion and scrubber operation, increases in those pollutants listed at R307-101-2 under "Significant," paragraphs (1) and (2)(a) are less than the thresholds shown. Accordingly, this project is a minor modification for those pollutants.

However, at R307-101-2, "Significant" paragraph (2)(b), the definition indicates that any increase for unlisted regulated pollutants is considered significant. IPSC provided an emission analysis that calculated possible increases in those unlisted pollutants against TLVs for those pollutants. This should satisfy the requirement at R307-405-6(2)(a)(i). Further, monitoring is exempted for this type of project based upon the provisions found at R307-405-6(6).

Completion

We appreciate the efforts of your staff in working with us. We assume that sufficient information has been provided to complete the process of issuing an AO. However, IPSC will continue to clarify questions and issues as requested to ensure the approval process proceeds smoothly. If, for some reason your office foresees any problem that could delay the issuance of an approval order, please contact us as soon as possible.

If you or any one of your staff have any questions, please contact Mr. Dennis Killian, Superintendent of Technical Services, at 435-864-4414, or dennis-k@ipsc.com.

Cordially,

S Gale Chapman

S. Gale Chapman
President and Chief Operating Officer
WJB for DKK
RJC/BP:jmg

Enclosure

cc: Blaine Ipson, IPSC
Reed Searle, IPA
Mike Nosanov, LADWP

BEST AVAILABLE CONTROL TECHNOLOGY EVALUATION FOR OXIDES OF NITROGEN

(REVISED)

for

INTERMOUNTAIN POWER SERVICE CORPORATION
INTERMOUNTAIN POWER PLANT (DELTA, UTAH)
REVAMP PROJECT

Prepared for:

LOS ANGELES DEPARTMENT OF WATER & POWER
111 North Hope Street
Los Angeles, CA 90012

August 2001

740073

Prepared by:

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TABLES

ACRONYMS

BACT	Best Available Control Technology
CO	Carbon Monoxide
CRF	Capital Recovery Factor
DAQ	State of Utah Division of Air Quality
EPA	United States Environmental Protection Agency
F	Fahrenheit
FGR	Flue Gas Recirculation
HP	High Pressure
IGS	Intermountain Generating Station
IPSC	Intermountain Power Service Corp
kW	Kilowatt
LADWP	Los Angeles Department of Water & Power
LNB	Low NOx Burner
LOI	Loss On Ignition
MMBtu	Million British Thermal Units
MW	Megawatt
NOI	Notice of Intent
NOx	Nitrogen Oxides
OFA	Overfire Air
O&M	Operating & Maintenance
ppm	parts per million
%	Percent
psi	pounds per square inch
SCR	Selective Catalytic Reduction
SIC	Standard Industrial Classification
SNCR	Selective Non-catalytic Reduction
SO_2	Sulfur Dioxide
VOC	Volatile Organic Compounds

IP10_003835

1.0 INTRODUCTION

Intermountain Power Services Corporation (IPSC) operates a two-unit coal-fired power plant, Intermountain Generating Station (IGS), in Delta, Utah. The Los Angeles Department of Water and Power (LADWP) is the "Operating Agent" of the facility and currently receives a significant amount of power generated by this power plant. IPSC proposes to revamp the power plant and increase power generation capacity by implementing a series of changes at the plant. IPSC prepared and submitted a Notice of Intent (NOI) on April 4, 2001 to the State of Utah Division of Air Quality (DAQ). The NOI has been corrected and modified as needed to clarify details of the proposed changes. The DAQ has requested IPSC to prepare a limited BACT analysis for oxides of nitrogen (NOx), considering certain specific NOx control technologies.

LADWP retained Parsons Engineering Science (Parsons ES) to perform the BACT evaluation for the IPSC Power Plant. Parsons ES has evaluated the NOx control technology options as specified by DAQ to reduce NOx emissions. This report presents the results of the BACT evaluation study.

2.0 PROJECT DESCRIPTION

The IGS is a fossil fuel-fired steam-electric generating station that primarily uses coal as fuel for producing steam to generate electricity (SIC Code 4911). The IGS fires both bituminous and subbituminous coals. Fuel oil and used oil are also combusted for light off and energy recovery.

The IGS is a two-unit facility currently operating at a rated capacity of 875 megawatts (MW) per unit (gross). The project covered by this analysis will increase operating capacity to approximately 950 MW per unit. Approximately 5.6 million tons of coal and 600,000 gallons of oil (fuel oil and used oil) will be used each year at the new rate of production. Boiler operating capacity will be rated at 6.9 million pounds per hour of steam flow at 2,975 psi.

Each unit is dry bottom wall-fired. Dual register low-NOx burners were installed during the original construction of each unit around 1986-87. Table 1 shows the typical average fuel characteristics of the coal currently used at the power plant.

IGS has in place bulk handling equipment for unloading, transfer, storage, preparation, and delivery of solid and liquid fuel to the boilers. No changes in this equipment are proposed. In addition, no changes in the usage of other raw materials or bulk chemicals are planned.

IPSC plans to enhance steam flow characteristics through the high pressure (HP) section of each turbine used to generate electricity. This would involve replacing the HP blade section with a modified design that would improve performance and reliability.

TABLE 1
TYPICAL IPSC COAL
PHYSICAL AND CHEMICAL CHARACTERISTICS

Type of Analysis	Parameter	Actual Average
Proximate	Volatile	38.1%
	Moisture	8.5 %
	Ash	9.2 %
	Fixed Carbon	44.2%
ASTM Other	Sulfur	0.52 %
	Heating Value	11,850 btu/lb
	Grindability	46 HGI
Ultimate	%C	66.47 %
	%H	4.77 %
	%N	1.28 %
	%S	0.52 %
	%O	9.26 %
Trace	Antimony	3.1 ppm
	Arsenic	12 ppm
	Barium	113 ppm
	Beryllium	0.38 ppm
	Cadmium	0.66 ppm
	Chromium	24 ppm
	Cobalt	2.9 ppm
	Copper	7.8 ppm
	Hydrogen Chloride	299 ppm
	Hydrogen Fluoride	63 ppm
	Lead	7.1 ppm
	Manganese	9.9 ppm
	Mercury	0.061 ppm
	Nickel	4.7 ppm
	Selenium	2.4 ppm
	Vanadium	5.6 ppm
	Zinc	7.4 ppm
Mineral (Ash)	Silicon Dioxide	63.2 %
	Aluminum Oxide	15.5 %
	Titanium Dioxide	0.8 %
	Iron Oxide	3.3 %
	Calcium Oxide	7.1 %
	Magnesium Oxide	2.9 %
	Potassium Oxide	1.5 %
	Sodium Oxide	2.1 %
	Phosphorus Pentoxide	0.2 %
	Sulfur Trioxide	4.2 %
	Silica Equivalent Value	86.4 %
	Base:Acid Ratio	0.21
	Fusion Temperature (Fluid)	2333+ F

NOTE:
Data provided here are estimates only, based on available industry-wide information combined with specific analyses. These are not limits, but arithmetic means bounded by wide ranges of concentrations that are dependent on fuel source and type. Solid fuels naturally have wide variability in characteristics. This fuel information is in no way intended to represent binding fuel parameters.

Combined improvements to other areas of the plant would increase plant-generating capacity. These modifications would consist of "de-bottlenecking" critical points that presently prevent the full use of present equipment. Other changes are needed for reliability, performance and/or routine maintenance purposes.

The existing pollution control devices at the power plant include dual register low-NOx burners, baghouse type fabric filters for particulate removal, and flue gas desulfurization scrubbers. The existing low-NOx burners provide a nominal 60% reduction in potential combustion NOx generation. The baghouse filters operate at nominal 99.95% efficiency. The wet sulfur dioxide (SO_2) scrubbers operate at nominal 90% efficiency. Control equipment for handling and transfer of solid material includes dust collection filters.

The proposed project includes modifications to the flue gas flow through scrubber modules to enhance SO_2 removal rates. Also, the project proposes a possible replacement of the existing dual register low-NOx burners with new technology ultra low-NOx burners. Alternatively, the project may utilize presently installed low-NOx burners, or identical "replacement-in-kind" burners, using new emission limits to keep the project minor for NOx.

3.0 REGULATORY REQUIREMENTS

IPSC has completed and filed a Notice of Intent (NOI) with the DAQ for the proposed IGS project. Rule 307-401-6 provides the conditions for issuing an approval order in response to a NOI. R307-401-6(1) requires the source to apply Best Available Control Technology. Rule 307-413 lists available exemptions from the NOI and approval order requirements. Exemptions exist for de minimis Emissions, Flexibility Changes, Replacement-in-Kind Equipment and Reduction of Air Contaminants. However, these exemptions do not appear to apply to the IGS project except for possible replacement-in-kind of low NOx burners.

Utah R307-101-2 provides the definition of BACT as follows:

"Best Available Control Technology (BACT) means an emission limitation and/or other controls to include design, equipment, work practice, operation standard or combination thereof, based on the maximum degree or reduction of each pollutant subject to regulation under the Clean Air Act and/or the Utah Air Conservation Act emitted from or which results from any emitting installation, which the Air Quality Board, on a case-by-case basis taking into account energy, environmental and economic impacts and other costs, determines is achievable for such installation through application of production processes and available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall applications of BACT result in emissions of any pollutants, which will exceed the emissions allowed by Section 111 or 112 of the Clean Air Act."

In addition, R307-410-6 requires that permit approvals be granted only if the degree of pollution control is at least as good as BACT as defined above, except as otherwise provided in the rules. The federal Clean Air Act requires that BACT be installed for pollutants that are major on new sources and modifications of existing sources in attainment or PSD areas. There is no federal requirement for BACT on pollutants that are minor on new sources or modifications; therefore, the state minor source BACT requirement is more stringent than the federal requirement. It would appear that the requirement is contrary to Utah Code Ann. 19-2-106; however, IPSC provisionally feels that a BACT analysis for this particular project is not unreasonable. No other provisions in the State rules provide relief from BACT for minor modifications. State guidance and policy does allow the DAQ to consider all site and project specific circumstances when making BACT determinations.

Typically BACT is determined following the United States Environmental Protection Agency (EPA) "top-down" methodology in which all applicable technologies are considered and first evaluated on technological feasibility considerations for the specific application. Those that are not deemed to be technologically feasible are set aside. The remaining technologies are ranked in descending order starting with the highest possible control efficiency. An economic analysis is conducted for each of these with the results (cost-effectiveness) being reported in dollars per ton of emissions removed. The technology that has the highest cost-effectiveness meeting a specified regulatory threshold is then typically selected as BACT provided other considerations such as energy, other environmental impacts, and site-specific aspects are deemed acceptable. If these are deemed unacceptable, the DAQ may alter the BACT determination accordingly.

The DAQ specifies that the following criteria be considered in determining BACT (Reference 1):

1. Energy Impacts – especially focusing on any significant or unusual direct energy penalties that may be required on either an absolute or on an incremental basis. (Reference 1, page 19)
2. Environmental Impacts – this should focus on non-air quality impacts (such as solid or hazardous waste generation or the discharge of polluted water) that may result due to the application of BACT; this analysis should also consider the generation of any toxic or hazardous air contaminants not regulated under the Clean Air Act. (Reference 1, pages 19-20)
3. Economic Impacts and Cost Calculations – in this analysis the costs of controls are quantified considering capital as well as operating costs. (Reference 1, pages 20-22, and page 23)
4. Other Considerations – this allows the consideration of factors, not necessarily economic that may affect the selection of BACT including incremental cost-effectiveness, ability to control more than one pollutant, the application of similar BACT in similar projects, the use of permit limits as control, etc. (Reference 1, pages 19-23)

Based on prior discussions, the DAQ has indicated to IPSC that the BACT evaluation should be performed for only NOx emissions. We have provided brief BACT discussions for other pollutants later in this report. For this NOx top-down analysis, IPSC has requested the consideration of five specific NOx control technologies for this BACT analysis. Finally, in addition to the factors listed above, DAQ policy otherwise considers $5,000 per ton reasonable for BACT for major modifications.

4.0 BACT ANALYSIS

Parsons ES has evaluated the NOx BACT technology based and non-technology based alternatives selected by IPSC and DAQ. Technologies considered include (1) ultra Low-NOx burners, (2) ultra Low-NOx burners with overfire air, (3) Mobotec Rotating Overfire Air (ROFA), (4) selective non-catalytic reduction (SNCR), and (5) selective catalytic reduction (SCR). Flue Gas Recirculation (FGR) was also initially considered as an applicable NOx control technology. While FGR is used frequently on gas-fired power plants, it is not considered a viable NOx control technology for coal-fired power plants. In fact, the EPA does not include FGR as a NOx control option for coal-fired power plants in its most recent edition of AP-42.

The use of a federally enforceable emission limitation for NOx is the non-technology based alternative also being considered as BACT, particularly if burners are not replaced, or are "replaced-in-kind."

Each of the BACT alternatives selected for evaluation is briefly discussed below:

4.1 Selective Catalytic Reduction – SCR uses ammonia or some other reducing agent (but mostly ammonia) in the presence of a catalyst (located in a region of specified flue gas temperatures, typically 550°F to 900°F) to reduce NOx emissions. A 70-90% reduction in NOx is achievable with SCR, depending on the level of NOx present. A 75% NOx reduction may be possible at large coal-fired power plants such as IPSC. SCR results in emissions of excess ammonia associated with ammonia slip of 5 – 10 ppm (1,000 to 2,000 tons per year). SCR has now been used for several years on coal-fired power plants in Europe (Germany, Austria, Denmark, etc.), Japan, and in the US (since 1995). Several different SCR configurations have been used and validated (Refs 4, 5) including high-dust (where the catalyst is placed upstream of the air preheater and the particulate controls); low-dust (catalyst after the particulate controls), etc.

Designs can accommodate a wide variety of coals (including specific ash, moisture, sulfur, calcium and arsenic contents) and can achieve specified levels of ammonia slip using either anhydrous or aqueous ammonia. Currently, over 300 applications of SCR are planned at US power plants. Indeed, current SCR implementation is limited from a schedule standpoint due to the large backlog of orders resulting in 52 weeks or more for delivery.

However, discussions with SCR vendors have indicated that no SCR units are currently installed on power plants that combust coal with characteristics similar to the coal burned at IPSC (i.e., Utah coals). Thus, at this time, SCR is not considered a demonstrated technology.

SCRs do have potential energy penalties as they incur additional pressure drop and require additional power to operate. The approximate installed cost for retrofit SCR at IGS is about $150MM ($79/kW). Costs vary widely depending on the coal characteristics (since that affects the nature and amount of catalyst to be used), whether it is a new installation or a retrofit and the configuration of the control train. Fixed O&M costs are roughly $3MM/yr ($1.84/kW-yr) for normal life installations and variable O&M costs are around $4MM/yr ($0.287/MWh). Costs were based on vendor data and information provided by IPSC (Reference 8).

BACT Criteria Summary for Selective Catalytic Reduction:

- Energy Impacts: Increased fan use to overcome pressure drop
- Environmental Impacts: Ammonia slip to the environment; waste disposal (spent catalyst)
- Economic Impacts: Estimated capital cost for SCR is 9.4 times the estimated capital cost of the entire IPSC improvement project
- Other Considerations: Long delivery times, incremental costs, currently not commercially demonstrated with Utah coal, this technology has not been determined as BACT for minor modifications for NOx in Utah or by the EPA

4.2 Selective Non-Catalytic Reduction – SNCR uses ammonia (or a similar reducing agent such as urea) injection directly into the combustion chamber at a location of specified temperatures. The ammonia reacts with NOx directly in the gas phase to reduce NOx emissions. SNCR could provide a maximum of around 40% reduction in NOx emissions from current levels at IPSC. SNCR has been used and is considered a proven technology for coal-fired power plants, especially for base-loaded units such as IPSC. Minimal energy penalties are associated with SNCR, primarily relating to operating the ammonia injection system. SNCR does result in emissions of excess ammonia called ammonia slip. The ammonia slip is ammonia that has not reacted with the NOx. However, ammonia slip is a SNCR design parameter that can be set at a specific level, typically less than 5 ppm (1,000 tons per year). The approximate installed retrofit capital cost for SNCR is about $18.4MM ($9-12/kW). Fixed O&M costs are estimated to be $200,000 per year ($0.11/kW-y) and variable O&M costs are $5MM / yr ($0.356/MWh) and can be higher depending on the cost of ammonia. Costs were based on information provided by IPSC (Reference 8).

BACT Criteria Summary for Selective Non-Catalytic Reduction:

- Energy Impacts: Negligible
- Environmental Impacts: Projected NOx reduction less than LNB with OFA. Additional SNCR results in ammonia emissions to the atmosphere from ammonia slip
- Economic Impacts: Annualized cost greater than LNB or permit limit, Capital cost of SNCR more than doubles cost of uprate project
- Other Considerations: Safety considerations associated with chemical transportation, storage, and handling, this technology has not been determined as BACT for minor modifications for NOx in Utah or by the EPA

4.3 Ultra Low-NOx Burners with Overfire Air – When combined with overfire air (OFA), an even greater NOx reduction can be attained with ultra Low NOx burners (around 50%), possibly achieving 0.17 lb/MMBtu NOx emissions at full load. No significant energy penalties would result beyond new fan requirements. However, CO emissions may increase two to four-fold (1,000 or more tons) as NOx emissions are reduced to low levels. No data are available on the impacts on other air pollutant emissions such as that for VOCs or other air toxics – however, these are expected to mirror the percentage increase in CO emissions. The estimated capital cost of these burners with overfire air is $22MM ($11.6/kW). Fixed O&M costs are in the range of $100K per year ($0.048/kW-yr) and variable O&M costs are in the range of $2MM / yr ($0.13/MWh). The capital costs were derived from vendor estimates provided by IPSC (Reference 8). Operating and maintenance costs were derived from IPSC experience with Low NOx burners and the costs associated with the fan (Reference 8). In addition, the use of ultra Low-NOx burners with overfire air can increase the Loss on Ignition (LOI) by as much as four times. This increase in LOI may render the ash unsuitable for sale and may require disposal. Costs have been included from loss of revenue for the reduced ash sales and costs for subsequent ash disposal.

BACT Criteria Summary for Ultra Low-NOx Burners with overfire air:

- Energy Impacts: Additional fan use, lower efficiency due to potentially increased LOI
- Environmental Impacts: Additional ash disposal; significantly higher CO emissions, somewhat higher VOC and air toxics emissions
- Economic Impacts: Loss of ash sales; installation of new fans; higher fan cost, retrofit ductwork, Capital cost of LNBs w/OFA more than doubles cost of uprate project
- Other Considerations: This technology has not been determined as BACT for minor modifications for NOx in Utah or by the EPA

4.4 Ultra Low-NOx Burners – New generation low-NOx burners being considered will be similar to burners manufactured by Babcock and Wilcox (Model DRB-4Z), which are three stage burners. Additional details of these burners are presented in Reference 2. These burners were recently developed and are now in commercial use (Reference 2).
Parsons estimates these burners can provide an additional 15% reduction in the NOx emissions at each IPSC unit. The estimated capital cost is approximately $9.9MM ($5.2/kW). Fixed O&M costs are in the range of $50K per year ($0.035/kW-yr) and variable O&M costs are negligible. These generic cost data are taken from vendor burner quotes and IPSC operating cost experience (Reference 8).

BACT Criteria Summary for Ultra Low-NOx Burners:

- Energy Impacts: Negligible compared to dual register Low NOx burners
- Environmental Impacts: A potential increase in CO emissions is possible along with the reduction in NOx emissions. Additional fuel use associated with the project will also result in a proportional increase in the emissions of VOC and other toxic compound emissions
- Economic Impacts: Replacement costs add significantly to the cost of the proposed uprate project
- Other Considerations: This technology has been determined as BACT for at least one minor modification for NOx in Utah and the EPA (Reference 9)

4.5 MOBOTEC Rotating Overfire Air (ROFA) – This technology is primarily overfire air. However, computer modeling is performed on the combustion chamber to properly design the system. In ROFA, tangentially placed secondary air ports on opposite sides of the furnace rotate the volume of air and fuel creating extensive mixing and a cyclonic effect. Through the use of a booster fan the secondary air is introduced into the furnace at about 170 miles per hour creating a cyclone. This cyclonic rotation results in an excellent mixture of air and fuel providing a very efficient combustion process. The tangentially placed air ports are usually installed at a higher level in the furnace than the conventional over fire air ports.

The manufacturer claims that ROFA can provide a 50% reduction in NOx emissions – although this is likely from a base on uncontrolled NOx emissions. Since the IPSC units already have existing low-NOx burners, the extent of further NOx reductions have to be evaluated on a site-specific basis. Likely emissions reductions are thought to be below 50%. ROFA has been installed commercially at a few power plants.

At the Carolina Power and Light Cape Fear Plant, ROFA has reduced NOx emissions from 0.60 lbs/MMBtu to 0.27 lbs/MMBtu while operating at 154 MW. This is the largest ROFA installation. Scaling this technology to the size of the IPSC units (i.e., to 950 MW each) is non-trivial since proper modeling and placement of the secondary air ports and resultant mixing is essential to achieve the claimed NOx reductions. Further, ROFA is designed for application to tangentially-fired or cyclonic boilers. ROFA used in wall-fired boilers may actually increase NOx emissions (Reference 8). As a result, this technology is still considered untested at units of this size and type, and, therefore, was eliminated from further consideration at this time. No cost estimates were developed for this technology.

4.6 Revised Permit Emission Limit for NOx (Synthetic Minor) – This method for meeting BACT is allowed for consideration as BACT is currently defined. Federally enforceable limits are commonly used to ensure compliance within PSD requirements. This method effectively ensures that no increases in allowable emissions will occur without threat of penalty. The ultimate advantage to the project and the State is direct evidence of compliance. Other advantages include minimal cost (no capital investment), and no increase in other pollutants due to impact of new pollution control technology. This preferred method of BACT allows the uprate project to proceed without installing any new NOx controls. Since the facility already has low-NOx burners, it is possible to stay below significant net increases in NOx with minor adjustments in how coal is combusted, such as burners-in-service arrangement, excess air, frequency of soot-blowing, etc.

BACT Criteria Summary for federally enforceable emission limit:

- Energy Impacts: Negligible with minor combustion modification
- Environmental Impacts: A potential increase in CO emissions is likely along with the reduction in NOx emissions due to combustion modification. Additional fuel use associated with the project will also result in a proportional increase in the emissions of VOC and other toxic compound emissions
- Economic Impacts: Negligible with minor combustion modification
- Other Considerations: This technology has commonly been determined as BACT for minor modifications for NOx in Utah and by the EPA

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OTHER BACT CONSIDERATIONS

Utah historically has considered pollution control equipment currently installed at IPP as BACT for similar permit actions. NSR engineering reviews have found that the current technology met BACT for previous permit revisions. For example, existing pollution controls were BACT for permits to allow fuel change to sub-bituminous coal (DAQE-028-97), and to allow combustion of used oil (BAQE-672-89).

The projected capital cost for the proposed uprate project is about $16MM. The economics of the project regarding revenue and payback are such that the addition of certain BACT technologies will kill the proposed project and any benefit for additional capacity at a time of energy crisis.

There have been no BACT determinations in the region requiring the use of most of the described technologies. One exception, as noted in Reference 9, was voluntary. Therefore, the average cost of BACT installation for this type of project approaches zero. To force any of these to be installed where previously not required (with the one voluntary exception in Reference 9) appears to exceed the authority of the DAQ as limited by Utah Code Ann. 19-2-106. The DAQ does have obvious authority in the rules and as shown by previous determinations to accept the recommendations of this BACT determination.

IPSC's NOx emissions averaged 25,144 tons/year for the years 1999 and 2000. The total emissions are divided equally between the two identical units when averaged over two years. The proposed project without new NOx control would increase NOx by 2,816 tons/year for total NOx emissions of 27,960 tons/yr. A decrease in NOx emissions of 2,777 tons/year from the above value would result in a minor modification, which is defined as "an increase in NOx emissions to less than 40 tons/year."

Table 2 summarizes the estimated plant wide (i.e., both units) emissions reduction for each technology (with the exception of a NOx permit limit revision), and the installed cost and the estimated cost per ton of NOx controlled. Details of the cost calculation are shown in Table 3. Incremental costs to meet minor modifications are also analyzed and presented. Table 4 provides the capital cost comparison for the base project and the base project with each NOx control technology studied.

TABLE 2
SUMMARY OF NOx CONTROL TECHNOLOGIES
FOR THE IPSC POWER PLANT
TWO 950 MW UNITS

TECHNOLOGY	ABSOLUTE EMISSION REDUCTION (TONS/YEAR)	INCREMENTAL EMISSION REDUCTION FOR MINOR MODIFICATION (TONS/YR)	INSTALLED COST (MM$)	ABSOLUTE COST EFFECTIVENESS ($/TON REMOVED) [2]	INCREMENTAL COSTS ($/TON REMOVED) [4]
Ultra Low NOx Burners	4,194	2,777	9.9	306	463
Ultra Low NOx Burners with Overfire Air	13,980	2,777	22.0	333	1,678
Rotating Overfire Air [1]	-		-	-	-
Selective Non Catalytic Reduction	11,184	2,777	18.4	647	1,244
Selective Catalytic Reduction	19,572	2,777	150.0	1,554 [3]	10,198

Notes:

[1] Not technologically demonstrated for this size and type of unit.
[2] See Table 3 for details.
[3] No operating installation on power plants that burn coal having the characteristics of the coal combusted at IPSC.
[4] Incremental Costs ($/ton) represent costs to only reach the minimum required NOx reduction of 2,777 tons in order to keep the proposed project a minor modification.

TABLE 3
COST CALCULATION DETAILS

Absolute Cost Evaluation

Technology	Pre-control NOx Emissions (tons/yr)	Absolute Emission Factor (% reduction)	Absolute Emission Reduction (tons/yr)	Capital Costs (MM$)	Unit Fixed O&M ($/kWh)	Total Fixed O&M (MM$/yr)	Unit Variable O&M ($/MWh)	Total Variable O&M (MM$/yr)	Life (yrs)	Interest Rate (%)	CRF	Absolute Annualized Cost (MM$/yr)	Absolute Cost Effectiveness ($/ton removed)
LNB	27,960	15	4,194	9.9	0.035	0.056	0.000	0	15	9	0.1241	1.284	306
LNB w/OFA	27,960	50	13,980	22.0	0.048	0.078	0.131	1.853	15	9	0.1241	4.660	333
SNCR	27,960	40	11,184	18.4	0.111	0.179	0.356	5.042	20	9	0.1095	7.237	647
SCR	27,960	70	19,572	150.0	1.837	2.967	0.287	4.066	10	9	0.1558	30.406	1,554

Incremental Cost Evaluation

Technology	Pre-control NOx Emissions (tons/yr)	Minor Modification Emissions Reduction (tons/yr)	Capital Costs (MM$)	Unit Fixed O&M ($/kWh)	Total Fixed O&M (MM$/yr)	Unit Variable O&M ($/MWh)	Total Variable O&M (MM$/yr)	Life (yrs)	Interest Rate (%)	CRF	Incremental Annualized Cost (MM$/yr)	Incremental Cost for Minor Modification ($/ton removed)
LNB	27,960	2,777	9.9	0.035	0.056	0	0	15	9	0.1241	1.284	463
LNB w/OFA	27,960	2,777	22	0.048	0.078	0.131	1.853	15	9	0.1241	4.660	1,678
SNCR	27,960	2,777	18.4	0.111	0.179	0.089	1.259	20	9	0.1095	3.454	1,244
SCR	27,960	2,777	150	1.837	2.967	0.14	1.981	10	9	0.1558	28.321	10,198

Notes:

[1] Costs shown are for the total plant capacity of 1,900 MW.

[2] Estimated costs are vendor specific with adjustments based on EPA's CUE Cost Workbook provided by IPSC (Reference 8).

[3] Capital Cost adjustments are from direct vendor information provided by IPSC (Reference 8).

TABLE 4
CAPITAL COST COMPARISON

Technology	Technology Capital Cost (MM$)	Base Project (MM$)	Total Cost (MM$)	Cost Ratio (Total/Base)
PERMIT LIMIT	0.0	16.09	16.09	1.00
LNB	9.9	16.09	25.99	1.62
LNB w/OFA	22.0	16.09	38.09	2.37
SNCR	18.4	16.09	34.49	2.14
SCR	150.0	16.09	166.09	10.32

5. CONCLUSIONS

Based on the regulatory requirements pertaining to NOx BACT, the various considerations that must be taken into account in the determination of BACT, and the reasonable cost-effectiveness thresholds used by DAQ, BACT for IPSC is discussed below:

Selective Catalytic Reduction
Given: 1) Extreme costs involved for adding SCR to keep this project a minor modification, 2) excessive costs when compared to project cost (see Table 4) for absolute NOx reductions, 3) additional ammonia emissions to the environment, 4) delivery times in excess of 52 weeks, 5) likely technical difficulties to be overcome when applying SCR with Utah coal since there are no operating installations, and 6) not determined as BACT for any other similar project.
Determination: SCR as a retrofit NOx control technology is rejected for this project.

Selective Non-Catalytic Reduction
Given: 1) Extreme costs involved for adding SCR to keep this project a minor modification, 2) Prohibitive costs (annualized) for both incremental and absolute NOx reductions, 3) NOx reductions less than LNB with OFA, 4) additional ammonia emissions to the environment, and 5) not determined as BACT for any other similar project.
Determination: SNCR as a retrofit NOx control technology is rejected for this project.

Rotating Over Fire Air
Given: ROFA is technically unproven for this size and type of unit.
Determination: ROFA as a retrofit NOx control technology is rejected.

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Flue Gas Recirculation (FGR)
Given: Not considered a viable NOx control technology for coal-fired power plants
Determination: FGR as a retrofit NOx control technology is rejected.

Ultra Low-NOx Burners with Overfire Air
Given: 1) Substantial increase in CO emissions to the environment, 2) increased loss on ignition (LOI) resulting in loss of ash sales revenue, 3) increase in land disposal of combustion wastes, 4) high incremental cost for minor mod NOx removal, and 5) not determined as BACT for any other similar project.
Determination: LNB w/OFA as a retrofit NOx control technology is rejected.

Ultra Low-NOx Burners
Given: 1) Ease of replacement, 2) moderate cost of installation and operation, 3) a potential minor increase in CO emissions, and 4) moderate incremental cost for minor modification NOx removal, and 5) has been determined voluntarily as BACT in one case for a similar project (Reference 9).
Determination: Ultra low NOx burners as a retrofit NOx control technology is recommended as BACT for NOx control if present burners are replaced.

Federally-Enforceable Permit Emission Limit
Given: 1) Ease of direct compliance, 2) minimal cost to operation, 3) minor increase in CO, 4) meets requirements under BACt definitions.
Determination: A new federally enforceable permit limit for NOx is recommended as BACT for NOx control if present burners are not replaced.

SUMMARY RECOMMENDATIONS

If the proposed project proceeds without replacing the present low-NOx burners, the use of a new federally enforceable permit limit for NOx is recommended.

If the proposed project proceeds with replacement of the low-NOx burners with new technology, the use of Ultra-low NOx burners is recommended.

6. BACT FOR OTHER POLLUTANTS

IPP has fabric filter baghouse type control devices for particulate emissions. The efficiencies of these devices meet present BACT for the boilers and support equipment.

IPP has wet-limestone flue gas desulfurization scrubbers for SOx and acid gas removal. The efficiencies of these devices meet present BACT for this type of project.

The combination of fabric filters and scrubbers on the boiler flue gas meets proposed BACT for mercury.

BACT has not been set for other pollutants from electric steam generating units such as IPP for this type of project.

7. REFERENCES

1. Best Available Control Technology, policy guidelines from Appendix II, The NOI Guide, Seventh Edition, Utah DAQ, DAQ Website 2001.
2. First Commercial Application of DRB-4Z Ultra-Low NOx Coal Fired Burner, Bryk, S. A., et al, BR-1710, presented at Power-Gen International 2000.
3. Analyzing Electric Power Generation Under the CAAA, Appendix No. 5, EPA 1998.
4. Performance of SCR on Coal-Fired Steam generating Units, Acid Rain Program, EPA 1997.
5. States' Report on Electric Utility Nitrogen Oxides Reduction Technology Options for Application by the OTAG, Appendix A, April 1996.
6. Proceedings from the FOMIS (Scientech) 1999 Winter Conference, "SNCR, SCR, And Gas Reburning - Technical Issues and Tradeoffs," James E. Staudt, Andover Technology Partners, Inc., 112 Tucker Farm Road, North Andover, MA 01845
7. "Status Report on NOx Control Technology & Cost Effectiveness for Utility Boilers," Northeast States Coordinating Air Use Management Committee, June 1998. Prepared by James E. Staudt, Andover Technology Partners, Inc., 112 Tucker Farm Road, North Andover, MA 01845
8. IPSC, Transmittals from Rand Crafts to P. C. Tranquill consisting of data and information from Reaction Engineering of Salt Lake City, Utah; B&W of Barberton, Ohio; Cormetech, Inc. of Durham, North Carolina and Advanced Burner Technologies of Morgan, Pennsylvania, dated May 21, 2001 and May 22, 2001.
9. See Utah Approval Order DAQE-186-98, subsequently superseded by EPA Region VIII.

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